Section III: IGS NO_X and CO Control Equipment Design and Anticipated Performance

3.1 Equipment Description

Control of NO_X at IGS is accomplished with the following equipment:

- **Low NO_X Burners:** The Dual Register Burner (DRB) style Low NO_X Burners (LNB's) designed and provided by Babcock & Wilcox (B&W) during original construction have provided stable and reliable combustion and emissions performance. The Intermountain steam generators are designed with 48 LNB's in an opposed-wall configuration. Combustion air is provided to the burners from compartmentalized, double-end fed windboxes controlling air to individual rows of burners installed on the front and rear walls. Each burner is equipped with outer and inner air control to balance air across each burner row.

  mechanical + structural

  Due to failures from thermal fatigue, the Unit 2 B&W DRB burners are scheduled for replacement in March 2004, pending approval and permitting. The new burners will be latest technology, high differential, LNB's manufactured by Advanced Burner Technology, Inc. (ABT) of Bedminster, New Jersey. ABT has ~~established a track~~ record in the power industry of equal or superior performance as compared to B&W. The new burners will be designed for the same capacity as the existing burners.

  Experience list?

- **Over Fire Air System:** An Over Fire Air (OFA) system manufactured by Babcock Power Services, Inc. (BPI) was installed on Unit 1 in March 2003 and is scheduled for completion on Unit 2 in March 2004, also with approval and permitting. BPI is an international designer/installer of power boilers and appurtenances. BPI, Inc. previously known as Babcock Borsig, Inc., DB Riley etc., has extensive experience in OFA and general boiler design. An OFA system experience list for BPI is shown in the Appendix, Section A-2.

  The OFA system consists of a set of 16 air ports installed on the front and rear furnace walls above the existing six burner columns. One additional port is installed near each sidewall to ensure optimal air distribution. A dedicated combustion air duct feeds air from the forced draft duct directly to the double-end fed, flow controlled OFA duct. The individual OFA ports are equipped with side-to-side, split-range flow control to allow 1/3, 2/3, or full port flow depending on combustion requirements.

3.2 Fuel and Air Flow Balancing

Actual date

RJM
U1 ✓
U2 ✓

Several years ago, extensive balancing of both the primary and secondary air flows was completed on both units and prior to the Unit 1 outage, we had no reason to believe that it had changed significantly. When Unit 1 was returned to service after the outage, we noticed that both the fuel and air (primary and secondary) flows were significantly out of balance. The secondary air flow balances were disrupted by construction

NO wasn't any different than prior to the outage
Just need to take balancing to next level
to lower NOx + CO

·also problems w/ OFA drive linkages

activities and the installation of the OFA ducts. The fuel balance (primary air flow) was changed through normal wear of the balancing components in the primary air lines.

To correct this problem, a full fuel and air balance regimen has been completed on Unit 1 in preparation for the OFA performance testing. The overall objective was to present each burner with an approximate stoichiometric ratio of fuel and air leaving as much air as possible to inject through the OFA ports to insure penetration coverage of the boiler cross section. The primary air lines were balanced empirically using "dirty air flow measurements" of the flow in each burner line. Adjustments were then made to new balancing dampers in each coal line installed after the outage for this testing (see Appendix, Section A-3 for balance data). The secondary air was balanced through observations of the flame wall separation and shape while the unit was in service and by cross sectional measurements of CO in the flue gas at the economizer outlet. (profiling)

Need

The result of the balancing is that the combustion process occurs initially in an air-lean environment reducing the formation of NO_X from fuel bound nitrogen sources. Additionally, the OFA ports are arranged and designed to blanket the upper furnace with a cooling layer of combustion air that further inhibits the formation of NO_X while still providing enough air and energy to burn out the CO.

3.3 OFA Design ~~Anticipated~~ Emissions Levels

Under the terms and test conditions specified in the contract, BPI provided a performance guarantee for emissions of both CO and NO_X at full load operating conditions as follows:

- NO_X: .37 lb/MMBTU
- CO: 100 ppm

Full load conditions are defined within the specification as follows:

▸ Superheat Outlet Temperature	1005° F
▸ Reheat Outlet Temperature	1005° F ?
▸ Total Air % Stoichiometry	118% (approx. 2.5% O_2)
▸ Coal Fineness (Min.% thru 200 Mesh)	70%
▸ Coal Fineness (Max. % ~~thru~~ retaining 50 Mesh)	1%
▸ Pulverizers In-service	7
▸ Boiler Surface Cleanliness	80-85%
▸ Furnace Surface Cleanliness	85-90%
▸ Superheat Attemperator Flow (Min.)	50,000 lbs/hr
▸ Reheat Attemperator Flow	0 lbs/hr

3.4 OFA System Boiler Model

Under separate ~~specification~~ contract, a boiler model was completed with GE Energy and Environmental Research (GE-EER), as an independent verification of BPI's design parameters.

One of the key recommendations resulting from the operation of the GE-EER combustion model focused on OFA penetration into the furnace. The model showed that under certain operating modes, 10 percent OFA may not be sufficient to ensure proper O_2 distribution throughout the boiler cross-section. This led to our upgrading the standard, manual OFA port control provisions to allow for independent, side-specific, remote control of the 1/3 and 2/3 damper sets. This gives us greater response capability with varying loads and mill configurations to bias the OFA distribution for minimizing emissions. Several prints of the various model runs completed in this analysis are shown in the Appendix, ~~Section A-4~~. graphs

The model predicted NO_x emissions reduction from OFA as summarized in Figure 3-1, Predicted NO_x Emissions GE-EER Model.

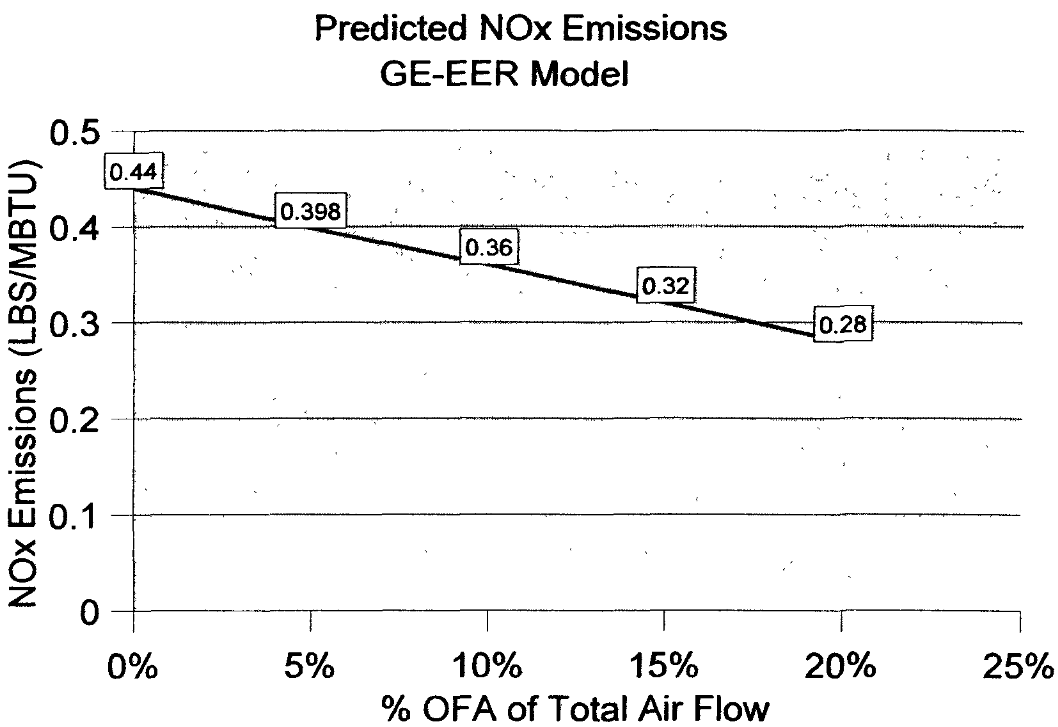

Figure 3-1, Predicted NOx Emissions GE-EER Model

The results of the model coincided closely with the guaranteed performance from BPI in their contract with 0.37 Lbs/MBTU with 10 percent OFA at 950 MWG.

The model also predicted the effect of OFA on CO emissions as summarized in Appendix, Section A-5. GE predicted much higher CO emissions than as guaranteed by BPI. The discrepancy between the two centered mostly around the belief GE-EER had that BPI's OFA nozzles would not cause the air to distribute across the full cross section of the boiler allowing large flow paths for CO to pass and cool below ignition temperature before full combustion.

They also did a prediction on the increase in ash LOI change as a result of OFA as shown in Figure 3-2, Ash LOI Increase GE-EER Model.

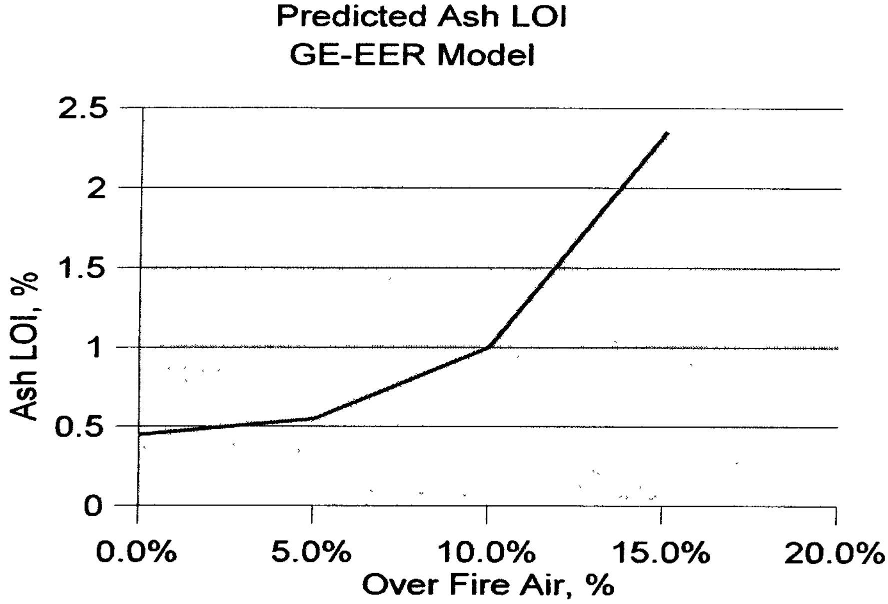

Figure 3-2, Ash LOI Increase GE-EER Model

Section IV: Test Methods and Procedures

4.1 General Description

The test methodology for flue gas analysis was conducted in accordance with the general procedures outlined in the ASME PTC 4.1 Steam Generators and PTC 19.10 flue and Exhaust Gas Analysis. Plant instrumentation, where possible, was utilized for the tests. Calibrated gas analyzers were connected to test probes inserted into test taps on the ductwork to obtain samples for the analysis of flue gases. The flue gas samples were mixed, chilled, dried and filtered before analysis.

During the test series, each test point was unique with varying OFA flow (four different configurations) and O_2 levels (five different operational points) to establish needed CO and NO_X levels. Each test was one to three hours in duration (with one hour of very stable conditions). Coal samples were taken during each test period. Prior to the start of each test, fly ash hoppers were emptied. At the end of each test period, fly ash samples were collected. Between each test period, operating variables were changed and soot blowing completed to maintain target main steam and reheat temperatures. Operational changes and stabilization took anywhere from one-half hour to one and one-half hours.

4.2 Test Conditions

A summary of the test conditions and results can be found in the Appendix, Section A-6, OFA Test Conditions. Each test was conducted for a nominal one and one-half to two hour period. The target was to achieve one hour of stable operating data. Some tests were lengthened in duration to achieve that goal. Also see reference Operations Test Plan and Bids

The coal source and supply were kept consistent by Operations during the test series to ensure emission variations were not a result of changes in fuel quality.

4.3 Data Collection

Test data collection consisted of information from the following sources and locations:

1. Plant data was utilized and collected from the data historian on the PI system which collects data from the Foxboro Digital Control System and Information Computer.
2. A flue gas test grid was established at the boiler economizer outlet utilizing rented high precision flue gas analyzers to measure O_2, CO, NO_X, and CO_2.
3. A flue gas probe, sampling system and analyzer were placed at the stack to collect CO readings (most homogenous location for measurement).

4. Field data collection points and Observations

5. Coal and flyash sample collection and analysis

6. CEM emissions data collected by flue gas probe at the stack

PI (plant information historian) was collected electronically every 30 seconds and the Test Grid data was collected electronically every 20 seconds. CEM data is summarized and made available on 15 minute intervals.

Coal samples were collected every 10 minutes from each of the seven coal feeders during the course of the test. Fly ash samples were collected at the completion of each test, while Operations was emptying fly ash hopper levels for setup on the following test.

Add

4.4 Flue Gas Test Grid at the Economizer Outlet

The flue gas test grid was setup at the boiler economizer outlet duct, which can be accessed on the 11th floor. Fourteen test probes (seven per side) are utilized, and each probe assembly actually has four probes at four different depths. This arrangement ~~establishes~~ a grid array with twenty-eight points per side, with a total of fifty-six points. Reference Test Grid Layout.

Each individual sample point is plumbed to a clear Plexiglas bubblier (so one can visually observe sampling flow rates) where it mixes with the other gas samples on its side. The water bath initially mixes, cools, and filters the flue gas. The sample is then chilled in an ice bath with a knockout bottle (where the condensate is collected), run through a vacuum pump, desiccant filter (moisture removal) and then sent through an air filter (dust removal). The flue gas samples are then plumbed to the gas analyzers where they are slipstream sampled via a flow regulator per each individual analyzer's own requirements. East and West side gas samples are then analyzed separately for CO (two separate analyzers with low and high ranges), O_2, CO_2, and NO_X. The data is collected via a Data Acquisition System (DAS) and stored on a computer and saved to a spreadsheet. This basic arrangement was also used for individual point profiling of the economizer outlet duct for burner tuning purposes. Reference Test Instrumentation List for detailed listing of the flue gas analyzers, Appendix, Section A-7.

4.5 CO Analyzer at the Stack

Additionally, a CO analyzer was leased + stationed at the stack to analyze averaged flue gas conditions at the 355-foot level. This is the same level that the flue gas points are sampled for the CEM analyzers. The gas sample was extracted via a probe from the duct and run through a double chiller and then sent to a low range CO analyzer.

Lookup Reference in 40 CFR Part 60 app A Reference Method 10

4.6 Coal Samples

Coal samples were collected throughout the test period from each of the seven pulverizer coal feeders. Special coal sample test taps were installed above each feeder inlet just below the coal silo down spout to get representative test samples. Coal sample size was approximately three quarts, taken from each of the seven feeders. This totaled five gallons which was then sealed and taken to the IPSC coal lab.

Proximate and ultimate coal analysis was conducted by IPSC's in-house coal lab following ASTM procedures.

4.7 Fly Ash Samples

Fly ash samples were collected from most of the performance tests. Maintenance had the fly ash system out for several of the tests. ISG (fly ash contractor) collected the fly ash samples. IPSC Operations pulled down the hoppers prior to each test period (beginning of each day) and between each test period.

Fly ash analysis was performed both by ISG utilizing a loss on ignition (LOI) abbreviated test and by IPSC utilizing ASTM standards for unburned carbon content.

4.8 Quality Assurance

Test analyzers at the stack and economizer outlet were calibrated at the beginning and end of each test series (day). Calibration gases were primary gas standards. Calibrations on station instrumentation were completed prior to the testing. Coal feeders were rotated out of service two weeks prior to the test to conduct restrictor installation and feeder calibrations. Station O_2 probes are calibrated on a weekly basis on a Preventative Maintenance (PM) program. Three analyzers were replaced prior to the testing. Reference Appendix, Section A-8.

4.9 Test Personnel

All testing was conducted by IPSC Engineering Services personnel. The Test Coordinator was Aaron Nissen, Engineering Supervisor. Mr. Nissen is a licensed Professional Engineer (PE) with the state of Utah and has 23 years of utility performance testing related experience.

Test Coordinator:
Aaron Nissen, Engineering Supervisor, PE

Analyzers & Test Grid:
Garry Christensen, Senior Engineer, PE
Rob Jeffery, Senior Analyst

Technical Support & Coal Sampling:
Dave Spence, Senior Engineer, PE
Bernell Warner, Draftsman

Flyash Sample Collection – ISG:
Rod Hansen, Rick Fowles, Kurt Aldredge

OFA System Controls and Dampers:
Ken Nielson, Senior Engineer, PE
Phil Hailes, Engineer

Babcock Power, Technical Support:
Dan Coats, Senior Field Engineering Manager

Section V: Test Results

Tabular results of the testing can be found in the Appendix, Section A-9. Graphical results of the testing can be seen in Figures 5-1 through 5-8.

5.1 NO_X Emissions

Curves Test~~ing~~ without OFA indicated that NO_X emissions could exceed~~ed~~ the current permit limit of 0.461 lbs/mbtu when the excess air levels were greater than 3.1 percent O_2 (see Figure 5-1). Since we prefer to operate with excess O_2 at 3 percent or greater for efficient combustion, this validates the need for installation of the OFA system. NO_X reduction without OFA was achieved with lower excess O_2 levels but, it was done at the expense of CO emissions and fly ash LOI's.

Figures 5-2 through 5-4 show the results through varying levels of percent OFA flow; Figure 5-4 at 14 percent flow through the OFA ducts which represents the maximum amount of OFA air. Even though both ~~the 1/3 and 2/3~~ dampers could theoretically be opened at the same time increasing the amount of air flow, ~~the design~~ was always for just the 2/3 dampers at full load. Opening both sets of dampers would only reduce duct pressure and reduce the penetration of OFA into the boiler cross section. Figure 5-5 shows that NO_X reduces linearly with the percent of OFA indicating that the best mode of operation for NO_X control is the maximum amount of OFA at full load conditions. Figure 5-5 corresponds very closely to that expected by both BPI and GE-EER in their design and modeling calculations.

Operational intent was to run just 2/3 open dampers

Figure 5-6 shows the relationship of NO_X emissions with percent of OFA air at varying levels of excess air. This graph shows that NO_X decreases with lower excess air and higher percent of OFA. It also shows that operation at 3 percent excess air (w/100 OFA) can achieve the same NO_X emissions as that at 2.5 percent excess air with full OFA flow. The line for 3.5 percent excess air appears to indicate better NO_X reduction than that of 3.0 percent but, that is against all theory, logic and prior testing and is probably a test anomaly.

5.2 CO Emissions

As expected, Figure 5-1 shows that CO increases ~~dramatically~~ as total excess air is reduced. The relationship between CO and O_2 appears to be exponential and the shape of the curve matches GE-EER's model and reference books on the subject (see Appendix, Section A-10).

The comparison of ~~Comparing~~ Figures 5-1 through 5-4, shows that as the percent of OFA flow increases beyond 10 percent, the exponent of the curve decreases, somewhat flattening out the curve of CO generation in the area of our normal operation. This decreasing of the exponent indicates that CO becomes less sensitive to O_2 levels with higher levels of OFA flow. This is probably the result of the reburn of the CO at the level of the OFA port entry into the boiler. It also indicates that there is probably good coverage of the OFA air curtain across the boiler when the 2/3 dampers are open. Even though comparison of Figures 5-1 and 5-4 shows that at 2.5 percent O_2, there is lower

CO without OFA than with full OFA, it is probably best from a CO standpoint to operate with full OFA to reduce the sensitivity. The reduction of the exponent expands the "Good Combustion Range" and improves the ability of the boiler to handle transients without exceeding short term CO limits.

Figure 5-7 shows the relationship between CO emissions and percent OFA flow at varying O_2 levels. This graph shows that at normal O_2 levels, CO is much more dependent on total O_2 levels than on percent OFA flow as the graph for each O_2 level above 2 percent is nearly flat. It also shows that at low O_2 levels, CO increases greatly with higher percent OFA. This indicates that the units should not be operated below 2 percent O_2 at anytime and preferably above 2.5 percent. Curve 1.75

Even though the general shape of the CO curve matched GE-EER's model, the values of CO were considerably less than expected. GE-EER expected high CO because they did not expect the OFA to extend fully into the boiler. These results seem to indicate that it did and this is the reason for the disparity. It should also be noted that BPI achieved their contract guarantee of less than 100 PPM CO at 10 percent OFA flow and 2.5 percent O_2.

5.3 Good Combustion Range

From both a CO and NO_x standpoint, the testing indicated that the best mode of operation for Unit 1 is to have the OFA system with the 2/3 damper and maximum OFA flow (Figure 5-4). This mode expands out the "Good Combustion Range" to allow for fluctuations and changes in coal quality. However; as previously mentioned, operation below 2 percent O_2 should be avoided and above 2.5 percent is preferred to minimize CO generation.

* state

5.4 Ash LOI

Figure 5-8 shows the effect of OFA on fly ash LOI. This graph shows an approximate 25 percent increase in LOI with OFA. This is much less than predicted by the GE-EER model. This is also due to GE-EER not expecting full penetration of OFA into the boiler. No comparisons have been made yet comparing LOI with excess O_2 but previous testing has shown a stronger relationship than that shown by OFA percent alone. In any case, the amount of LOI is still acceptable and represents only small decreases in boiler efficiency. Obviously, the best way to lower LOI is to increase O_2 in the boiler. Operation with OFA will allow higher O_2 levels while still maintaining NO_x emissions.

5.5 VOC's

Even though no specific testing was done during this test on VOC's, it can be deduced from the reaction of CO and LOI that the installation of the OFA system will not result in a significant increase in VOC emissions. This fact was verified during testing on Unit 1 that was completed last spring to prepare the application for Unit 3 permitting which showed ~~practically~~ no VOC's increase with the unit at full load and OFA in-service.

Add Coal Source

Used 1 specific coal source

NOx curves change w/change of coal supply

State VOC is low (can't measure) can't correlate w/ LOI

Section VI: Conclusions ~~and Recommendations~~

Based on the results of the testing and analysis, the following conclusions ~~and recommendations~~ can be made:

1. The OFA system ~~works~~ verify as intended and reduces the NO_x emissions from Unit 1 by approximately 14 percent when compared to operation without OFA and 2.5 percent excess O_2. The amount and level of reduction compare favorably with those predicted by both BPI and GE-EER. 25-30 ?

2. The OFA system allows the unit to operate with higher excess air levels and still achieve the required NO_x emission rate.

3. Operation of the OFA system with the 2/3 dampers fully open results in less sensitivity to CO emissions than operation without OFA. OFA operation flattens out the curve for CO generation thus reducing the chance of large fluctuations in CO generation. This indicates that the OFA system has good coverage across the cross sectional area of the boiler at its admission point. The BPI contractual guarantee of CO generation of less than 100 PPM with 10 percent OFA and 2.5 percent excess oxygen was achieved.

4. CO generation is very sensitive to fuel and air flow balancing. Both the primary and secondary air flows should be checked for balance periodically to insure minimum CO generation.

5. While the OFA system controlled NO_x with relatively high excess air levels for this test, changes in coal quality may require operation at low levels of excess air even with the OFA system in service. Current and future emissions limits for CO should allow some room for operation at low levels of excess air so that the NO_x targets can be achieved.

6. The OFA system expands the "Good Combustion Range" by reducing NO_x removal with higher excess air and reduces CO generation with lower excess air.

7. Fly ash LOI's increase with increased percent of air to the OFA system and decreased percent of excess O_2. The most efficient combustion occurs with the highest allowable excess air level while still achieving required NO_x emission rates.

8. Since CO generation is actually less with the OFA system in-service than without, VOC's are probably almost completely oxidized because of their lower ignition temperature compared to CO. VOC's should be ~~practically~~ nonexistent in the IGS flue gas with or without OFA. increases negligibly

? limited test data to support
check post-outage tests

secondary combustion

performance
PAW - fineness checks
No biasing

problem:
↓O2 generate 3x
however CO removal 40%

IP7_035524

Abbreviations

Intermountain Generating Station	(IGS)
Over Fire Air	(OFA)
Intermountain Power Project	(IPP)
Intermountain Power Service Corporation	(IPSC)
Babcock & Wilcox	(B&W)
Advanced Burner Technology, Inc.	(ABT)
Babcock Power Services, Inc.	(BPI)
Dual Register Style Low NOx Burners	(DRB)